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September 26, 2006

**VIA OVERNIGHT DELIVERY AND ELECTRONIC FILING**

Mary L. Cottrell, Secretary  
Department of Telecommunications and Energy  
One South Station  
Boston, MA 02110

Re: Bay State Gas Company, D.T.E. 06-36

Dear Ms. Cottrell:

On March 31, 2006, Bay State Gas Company ("Bay State") filed with the Department of Telecommunications and Energy ("Department"), its System Protection Plan for Grandfathered Overtakes ("March 31, 2006 Filing"), as required by the Department's Order in D.T.E. 05-27. The March 31, 2006 Filing included proposed revisions to Bay State's tariffs M.D.T.E. No. 35 (Index Page, Section 2, Section 13 and Appendix C) and M.D.T.E. No. 36 with a proposed Effective Date of September 1, 2006. Subsequently, on June 15, 2006, Bay State re-filed its proposed M.D.T.E. No. 35 (Index Page, Section 2, Section 13 and Appendix C) and M.D.T.E. No. 36, with the sole changes of a revised Effective Date of December 1, 2006 and Issue Date of June 15, 2006. At this time, Bay State is again re-filing its proposed M.D.T.E. No. 35 (Index Page, Section 2, Section 13 and Appendix C) and M.D.T.E. No. 36, with the sole changes of a revised Effective Date of February 1, 2007 and Issue Date of September 26, 2006. The revised Effective Date is necessary in order to accommodate the procedural schedule established for this docket.

Please do not hesitate to contact me at (508) 836-7394 or Robert L. Dewees, Jr., of Nixon Peabody LLP, at (617) 345-1316 with any questions concerning this filing.

Very truly yours,

Patricia M. French

cc: Julie Howley Westwater, Esq., Hearing Officer, DTE  
Kevin Brannelly, Director, Rates and Revenue Requirements, DTE  
George Yiankos, Director, Gas Division, DTE  
Jamie M. Tosches, Esq., Office of the Attorney General

**DISTRIBUTION AND DEFAULT SERVICE  
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**2.0            DEFINITIONS**

Adjusted Target Volume ATV	The volume of Gas determined pursuant to Section 12.3.
Aggregation Pool	One or more Customer accounts whose Gas Usage is served by the same Supplier and aggregated pursuant to Section 24.6 of these Terms and Conditions for operational purposes, including but not limited to nominating, scheduling and balancing gas deliveries to Designated Receipt Point(s) within the associated Gas Service Area.
Annual Reassignment Date	Five (5) Business Days prior to November 1 of each year when the Company reassigns Capacity to Suppliers pursuant to Section 13.6 of these Terms and Conditions.
Assignment Date	Five (5) Business Days prior to the first Day of each month when the Company assigns Capacity to Suppliers pursuant to Section 13.4 of these Terms and Conditions.
Authorization Number	A unique number generated by the Company and printed on the Customer's bill that the Customer must furnish to the Supplier to enable the Supplier to obtain the Customer's Gas Usage information pursuant to Section 24.4, and to initiate or terminate Supplier Service as set forth in Section 24.5 of these Terms and Conditions.
Business Day	Monday through Friday excluding holidays recognized by the Company, which will be posted on the Company's website on an annual basis. If any performance date referenced in these Terms and Conditions is not a Business Day, such performance shall be the next succeeding Business Day.
Btu	One British thermal unit, i.e., the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sixty degrees (60°) Fahrenheit. MMBtu is one million Btus.

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Capacity	Pipeline Capacity, Underground Storage Withdrawal Capacity, Underground Storage Capacity and Peaking Capacity as defined in these Terms and Conditions.
Capacity Allocators	The proportion of the Customer's Total Capacity Quantity that comprises Pipeline Capacity, Underground Storage Withdrawal Capacity and Peaking Capacity.
Capacity Exempt Customer	Any Customer receiving Distribution Service whose TCQ is equal to zero as provided for in either Section 13.3.3 or Section 13.3.5 of these Terms and Conditions.
City Gate	The interconnection between a Delivering Pipeline and the Company's distribution facilities.
Company	<u>Bay State Gas Company</u>
Company Gas Allowance	The difference between the sum of all amounts of Gas received into the Company's distribution system and the sum of all amounts of Gas delivered from the Company's distribution system as calculated by the Company for the most recent twelve (12) month period ending July 31. Such difference shall include, but not be limited to, Gas consumed by the Company for its own purposes, line losses and Gas vented and lost as a result of an event of Force Majeure, excluding gas otherwise accounted for.
Company-Managed Supplies	Capacity contracts held and managed by the Company in accordance with governing tariffs, but made available to the Supplier pursuant to Section 13.9 of these Terms and Conditions, including supply-sharing contracts and load-management contracts.
Consumption Algorithm	A mathematical formula used to estimate a Customer's daily consumption.
Critical Day	In accordance with Section 19.0 of these Terms and Conditions, a Day declared at any time by the Company in its reasonable discretion when unusual operating

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conditions may jeopardize operation of the Company's distribution system.

Customer	The recipient of Default Service and/or Distribution Service whose Gas Usage is recorded by a meter or group of meters at a specific location and who is a Customer of record of the Company.
Daily Baseload	The Customer's average usage per day that is assumed to be unrelated to weather.
Daily Index	<p>The mid-point of the range of prices for the respective New England Citygates as published by <u>Gas Daily</u> under the heading "Daily Price Survey, Midpoint, Citygates, Algonquin citygates" and "Daily Price Survey, Midpoint, Citygates, Tennessee/Zone 6 (delivered)" for the relevant Gas Day listed under "Flow date(s)".</p> <p>In the event that the <u>Gas Daily</u> index becomes unavailable, the Company shall apply its daily marginal cost of gas as the basis for this calculation until such time that MDTE approves a suitable replacement.</p>
Day or Gas Day	A period of twenty-four (24) consecutive hours beginning at 10:00 a.m., E.T., and ending at 10:00 a.m., E.T., the next calendar day, or other such hours used by the Delivering Pipeline.
Default Service	Gas commodity service provided to a Customer who is not receiving Supplier Service, in accordance with Section 15.0 of these Terms and Conditions. The provision of Default Service shall be the responsibility of the Company and shall be provided to the Customer by the Company or its designated supplier pursuant to law or regulation.
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Delivering Pipeline	The interstate pipeline company that transports and delivers Gas to the Designated Receipt Point.
Delivery Point	The interconnection between the Company's facilities and the Customer's facilities.
Design Winter	The forecasted Winter during which the Company's system experiences the highest aggregate Gas Usage.
Designated Receipt Point	For each Customer, the Company designated interconnection between a Delivering Pipeline and the Company's distribution facilities at which point, or such other point as the Company may designate from time to time for operational purposes, the Supplier will make deliveries of Gas for the Customer's account.
Designated Representative	The designated representative of the Customer, who shall be authorized to act for, and conclusively bind, the Customer regarding Distribution Service in accordance with the provisions of Section 25.0 of these Terms and Conditions.
Distribution Service	The transportation and delivery by the Company of Customer purchased Gas on any Gas Day from the Designated Receipt Point to the Customer's Delivery Point pursuant to these Terms and Conditions.
Gas	Natural gas that is received by the Company from a Delivering Pipeline at the Designated Receipt Point and delivered by the Company to the Delivery Point for the Customer's account. In addition, the term shall include amounts of vaporized liquefied natural gas and/or propane-air vapor that are introduced by the Company into its system and made available to the Customer as the equivalent of natural gas that the Customer is otherwise entitled to have delivered by the Company.

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Gas Service Area	An area within the Company's distribution system as defined in Section 4.0 of these Terms and Conditions, for the purposes of administering capacity assignments, nominations, balancing, imbalance trading, and Aggregation Pools.
Gas Usage	The actual quantity of Gas used by the Customer as measured by the Company's metering equipment at the Delivery Point.
Heating Factor	The Customer's estimated weather-sensitive usage per degree day.
Interruptible Distribution Service	Transportation Service provided to the Customer by the Company that is subject to curtailment by the Company and/or the Customer in accordance with Section 17.0 of these Terms and Conditions.
Maximum Daily Peaking Quantity (MDPQ)	The portion of a Customer's TCQ identified and allocated as Peaking Capacity, such that the maximum daily amount of Gas that can be withdrawn from a Suppliers' Peaking Service Account pursuant to Section 16.0 of these Terms and Conditions shall be equal to the sum of the Customers' MDPQs in a Supplier's Aggregation Pool.
MDTE	The Massachusetts Department of Telecommunications and Energy.
Month	A calendar month of Gas Days.
Monthly Index	The average of the Daily Indices for the relevant Month.

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Nomination	The notice given by the Supplier to the Company that specifies an intent to deliver a quantity of Gas to the Designated Receipt Point(s) on behalf of a Customer, including the volume to be received, the Designated Receipt Point(s), the Delivering Pipeline, the delivering contract(s), the shipper, and other such non-confidential information as may be reasonably required by the Company.
Off-Peak Season	The consecutive months May to October, inclusive.
Operational Flow Order	The Company's instructions to the Supplier to take such action as conditions require, including, but not limited to, diverting Gas to or from the Company's distribution system pursuant to Section 19.0 of these Terms and Conditions.
Peak Day	The forecasted Gas Day during which the Company's system experiences the highest aggregate Gas Usage as approved by the MDTE.
Peaking Capacity	Capacity normally used by the Company to provide Peaking Service.
Peak Season	The consecutive months November to April, inclusive.
Peaking Service	A supplemental supply service provided by the Company to effectuate the assignment of pro-rata shares of the Company's Peaking Capacity.
Peaking Service Account	An account whose balance indicates the total volumes of Peaking Service resources available to a Supplier, where the maximum balance in the account shall equal the Peaking Supply assigned to the Supplier pursuant to these Terms and Conditions.



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Peaking Service Rule Curve	A system of operational parameters associated with the use of the Company's Peaking Capacity including, but not limited to, indicators of the necessary levels of Peaking Supply that must be maintained in Suppliers' Peaking Service Accounts in order for the Company to meet system demands under Design Winter conditions. The Company will post the Peaking Service Rule Curve on its Website as identified in Section 23.0 of these Terms and Conditions
Peaking Supply	The aggregate amount of peaking supply required to meet the Company's forecasted peaking-supply needs during a Design Winter.
Peaking Supply Allocator	An allocation factor that represents the proportion of a Customer's estimated Gas Usage during the Design Winter that is generally served with Peaking Service supplies.
Pipeline Capacity	Transportation capacity on interstate pipeline systems normally used for deliveries of Gas to the Company, exclusive of Underground Storage Withdrawal Capacity and Underground Storage Capacity.
Pre-Determined Allocation	Instructions from the Supplier to the Company for the allocation of discrepancies in confirmed nominations among the Supplier's Aggregation Pools and/or Customers as set forth in the Supplier's Service Agreement.
Reference Period	A period of at least twelve (12) months for which a Customer's Gas Usage information is typically available to the Company.

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Supplier	Any entity licensed by the MDTE to sell Gas to retail Customers in Massachusetts that has met the Company's requirements set forth in these Terms and Conditions, and that has been designated by the Customer to supply Gas to a Designated Receipt Point for the Customer's account.
Supplier Service	The sale of Gas to a Customer by a Supplier.
Therm	An amount of Gas having a thermal content of 100,000 Btus.
Total Capacity Quantity	The total amount of Capacity assignable to a Supplier (TCQ) on behalf of a Customer.
Underground Storage	Contracts for capacity in off-system storage Capacity facilities used to accumulate and maintain gas inventories for redelivery to the Company's city gates.
Underground Storage Withdrawal Capacity	Capacity for the withdrawal of gas inventories maintained in off-system storage facilities, as well as the transportation capacity used to deliver such gas to the Company's city gates.
Winter	The period November 1 through March 31.

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**13.0            CAPACITY ASSIGNMENT**

**13.1            Applicability**

Section 13.0 of these Terms and Conditions applies to all Suppliers providing Supplier Service to a Customer or Customers taking Daily-Metered or Non-Daily Metered Distribution Service from the Company pursuant to Section 11.0 or 12.0, respectively, of these Terms and Conditions. Section 13.0 shall also apply, to the extent noted herein, to any Customer acting as its own Supplier and taking Daily-Metered or Non-Daily Metered Distribution Service from the Company. The Company will assign and the Supplier shall accept each Customer's pro-rata shares of Capacity, if any, as established in accordance with this Section.

**13.2            Identification of Capacity for Assignment**

13.2.1            On or before September 1 of each year, the Company shall post on its Website or other such means the Capacity to be made available for assignment to Suppliers on each of twelve Assignment Dates beginning the following October. Such posting shall list, by Gas Service Area, all resource contracts eligible for assignment, the Capacity resource-allocation percentage by load factor, and the associated Capacity cost by load factor. Such posting shall also provide notice of any potential or pending contract change, including known and disclosable contract terminations, that are scheduled to require action by the Company between September 1 of the current year and October 31 of the next year. For capacity assignments occurring November 1, 2000, resource-allocation percentages and resource-allocation costs will be posted by the Company no later than October 22, 2000.

13.2.2            The Company shall post on its Website or other such means notice to Suppliers of any unscheduled contract changes that would affect the Capacity resource-allocation percentage or the associated Capacity cost. The Company will affirmatively notify all Suppliers serving Customers in the Company's system via electronic mail, facsimile or telephone, that such change has been posted. Such posting shall identify the contract under renegotiation and describe the nature of the renegotiation to the extent permitted by applicable confidentiality agreements. Such notice shall also provide an opportunity for Suppliers to comment on the contract under renegotiation. The Company shall further notify Suppliers of the results of such renegotiation no less than 60 days prior to the effective date of the contract change.

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- 13.2.3 Capacity assigned by the Company may include Company-Managed Supplies that effectuate, at maximum tariff rates or lesser rate paid by the Company, the assignment of certain capacity contracts, including Canadian, Section 7(c) and other contracts that are not assignable to third parties.
- 13.3 Determination of Pro-Rata Shares of Capacity
- 13.3.1 The Company shall establish a Total Capacity Quantity ("TCQ") for each Customer taking Distribution Service. The TCQ represents the total amount of Capacity assignable to a Supplier on behalf of a Customer.
- 13.3.2 For a Customer receiving Default Service on or after November 1, 2000, the TCQ shall be the Customer's estimated Gas Usage on the Peak Day as determined by the Company each October prior to the Customer's enrollment into Supplier Service. The Company shall derive such estimate using a Daily Baseload and a Heating Factor based upon the Customer's historic Gas Usage during the Reference Period, or the best estimates available to the Company should actual Gas Usage information be partially or wholly unavailable.
- 13.3.3 For a Customer receiving only Distribution Service from the Company on February 1, 1999, or who had a written request filed with the Company on or before February 1, 1999 to receive only Distribution Service, the TCQ shall be zero except in cases where the Customer elects to have capacity assigned to its Supplier pursuant to Section 13.10, when the TCQ shall be less than or equal to the Customer's estimated Gas Usage on the Peak Day as determined by the Company. The Company shall derive such estimate using a Daily Baseload and a Heating Factor based upon the Customer's historic Gas Usage during a Reference Period ending in October 1999.
- 13.3.4 For a Customer that has converted from receiving Default Service to receiving only Distribution Service during the period beginning February 2, 1999 through and including March 31, 2000, the TCQ shall be zero until October 31, 2000, when the TCQ shall be changed to equal the Customer's estimated Gas Usage on the Peak Day as determined by the Company. The Company shall derive such estimate using a Daily Baseload and a Heating Factor based upon the Customer's historic Gas Usage during a Reference Period ending in October 1999. In the event that the Customer returns to Default Service prior to November 1, 2000, or if the Customer converts from daily-metered Distribution Service to non-daily-metered Distribution Service prior to November 1, 2000, the TCQ for the Customer shall be changed from zero to equal the Customer's estimated Gas Usage on the Peak Day as established above.

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- 13.3.5 For a new Customer taking only Distribution Service as its initial service after February 1, 1999, the TCQ shall be zero except in cases where the Customer is a new Customer of record at a meter location where a former Customer of record received firm service from the Company any time during the preceding twenty-four (24) months, when the TCQ established by the Company for the former Customer shall become the TCQ for the new Customer. The Company will reduce said TCQ value for the new Customer upon a demonstration by the new Customer, or its designated representative, that a material and permanent difference between the former Customer's load profile and the new Customer's load profile warrants such a reduction. In the event that Default Service is provided at a new meter location for Gas Usage associated with new construction or an existing structure converting to natural gas service, the TCQ shall be zero, provided that the Customer initiates Supplier Service in accordance with Section 24.5 of these Terms and Conditions within 120 days of gas flow, or within 60 days of gas flow for Customers with annual volumes of 40,000 therms per year or more. Upon application by a new Customer, the LDC will provide that Customer with a description of the Customer's service options, a list of Suppliers authorized to provide service on its system and contact information for those Suppliers.
- 13.3.6 Once the Company establishes a TCQ for a Customer pursuant to this Section 13.3, it shall remain in effect for the purpose of determining the Customer's pro-rata shares of Capacity until such time that the Customer returns to Default Service. The Company shall establish a new TCQ value for the Customer pursuant to Section 13.3.2 if the Customer elects to take Supplier Service after returning to Default Service, unless otherwise established herein.
- 13.3.7 Notwithstanding the provisions of Section 13.3.6, where a Customer's TCQ is established on the basis of less than 12-months historical data, the TCQ may be recalculated at the Customer's request, or by request of the Customer's designated representative, upon the collection of 12-months of usage data. In the event that the TCQ established on the basis of 12-months usage data differs significantly from the TCQ initially established, the Company shall adjust the Customer's TCQ to be consistent with the 12-months usage data. Upon request by the Customer, or the Customer's designated representative, the Company shall change a Customer's TCQ where an error has occurred in the calculation of the TCQ or where the Customer, or its designated representative, demonstrates that a material and permanent change in the Customer's load profile warrants such an adjustment in the Customer's TCQ.

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- 13.3.8 The Company shall determine the pro-rata shares of Pipeline Capacity, Underground Storage Withdrawal Capacity and Peaking Capacity assignable to a Supplier on behalf of a Customer as the product of the Customer's TCQ times the applicable Capacity Allocators. The Capacity Allocators for each class of Customers billed under the Company's Schedule of Rates shall be set forth annually in Appendix A to these Terms and Conditions.
- 13.3.9 The Company shall determine the pro-rata share of Underground Storage Capacity assignable to a Supplier on behalf of a Customer consistent with the tariffs governing the associated Underground Storage Withdrawal Capacity.
- 13.3.10 The Company shall determine the pro-rata shares of Peaking Supply assignable to a Supplier in accordance with Section 16.0 of these Terms and Conditions.
- 13.4 Capacity Assignments
- 13.4.1 On each Assignment Date, the Company will assign to the Supplier the pro-rata shares of Capacity on behalf of each Customer as determined by the Company in accordance with Sections 13.2, 13.3 and 13.7.
- (1) The total amount of Pipeline Capacity, Underground Storage Withdrawal Capacity and Peaking Capacity assigned to the Supplier on behalf of the Customers in an Aggregation Pool shall, subject to the provisions of Section 13.4.2, be equal to the cumulative sum of the pro-rata shares of Pipeline Capacity, Underground Storage Withdrawal Capacity and Peaking Capacity for all Customers enrolled in said Aggregation Pool as of five (5) Business Days prior to the Assignment Date.
  - (2) Whenever the Company assigns incremental Underground Storage Withdrawal Capacity to the Supplier, the Company shall also assign to that Supplier additional Underground Storage Capacity pursuant to Section 13.8.
  - (3) The Peaking Capacity assigned to the Supplier shall establish the MDPQ for the Aggregation Pool in the Supplier's Service Agreement. In the event that the Company increases a Supplier's MDPQ, the Company shall also assign to that Supplier additional Peaking Supply pursuant to Section 16.0.
- 13.4.2 Except for the assignment of the initial block of capacity, the Company shall execute capacity assignments in increments of 200 MMBtus. The Supplier shall accept an initial

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increment of 500 MMBtus of Capacity on the first Assignment Date when the sum of the pro-rata shares of Capacity to be assigned to the Supplier pursuant to Section 13.4.1 is equal to or greater than 400 MMBtus. The Supplier shall accept additional increments of Capacity in blocks of 200 MMBtus on the following Assignment Dates commensurate with any cumulative increase in the sum of pro-rata shares of Capacity assignable to the Supplier that are equal to or greater than 150 MMBtus. Each increment of Capacity accepted by the Supplier shall comprise Pipeline Capacity, Underground Storage Withdrawal Capacity and Peaking Capacity in proportion to the cumulative increase of the pro-rata shares of assignable Capacity as established in accordance with Section 13.4.1.

- 13.4.3 The Supplier shall accept, on behalf of any Customer taking Daily-Metered Distribution Service pursuant to Section 11.0 of these Terms and Conditions, and not combined by the Supplier into an Aggregation Pool under Section 24.6, the assignment of Capacity in the amount equal to the Customer's TCQ, as established pursuant to Section 13.3. Daily-Metered Customers shall be eligible for assignment of Capacity pursuant to the provisions of Section 13.4.2 to the extent that such Customers are combined by a Supplier into an Aggregation Pool within a designated Gas Service Area. In the event that a Customer is acting as its own Supplier, the Company shall assign Capacity to the Customer in an amount equal to the Customer's TCQ, as established pursuant to Section 13.3. In no case, shall a Customer who is acting as its own Supplier be eligible for the assignment of Capacity pursuant to the provisions of Section 13.4.2.

13.5 Release of Contracts

- 13.5.1 With the exception of Company-Managed Supplies, capacity contracts shall be released by the Company to the Supplier, at the maximum tariff rate or lesser rate paid by the Company and including all surcharges, through pre-arranged capacity releases, pursuant to applicable laws and regulations and the terms of the governing tariffs. In lieu of such capacity release, the Supplier may authorize the Company to retain the capacity for management and cost mitigation under the Company's Capacity Mitigation Service pursuant to Section 13.11 of these Terms and Conditions.
- 13.5.2 Capacity contracts released to a Supplier on an Assignment Date shall be released for a term beginning on the first day of the Month following the Assignment Date through the termination date of the respective capacity contract being assigned.
- 13.5.3 The Company reserves the right to adjust releases of Underground Storage Withdrawal Capacity in the event that fifty percent (50%) or more of the total Underground Storage

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Withdrawal Capacity serving a Gas Service Area has been assigned to Suppliers. Such adjustments may include, but not be limited to, the reassignment of certain Underground Storage Capacity and Underground Storage Withdrawal Capacity as Company-Managed Supplies in order for the Company to maintain operational control over capacity resources associated with system balancing, and/or the retention of specific capacity resources associated with system balancing and the implementation of a balancing charge to offset the associated costs.

In order to provide notice of the potential for such an adjustment, the Company will post information regarding its customer-migration statistics each September 1, including the percentage of Underground Storage Withdrawal Capacity assigned to Suppliers in accordance with this section. To the extent that the Company determines that such adjustment is necessary, based on the level of capacity assigned to Suppliers, the Company shall notify Suppliers of the terms of the proposed adjustment no later than 90 days prior to the implementation of such adjustment.

13.6      Annual Reassignment of Capacity

- 13.6.1      On each Annual Reassignment Date, the Company shall adjust the capacity assignments previously made to a Supplier to conform with the Company's resource and requirements plans. Such previously assigned Capacity shall be replaced by the assignment to the Supplier of the pro-rata shares of the same or similarly situated Capacity on behalf of the Customers enrolled in the Supplier's Aggregation Pools (as of the first day of the Month following the Annual Reassignment Date).
- 13.6.2      If the reassignment of Underground Storage Withdrawal Capacity requires adjustments to the Underground Storage Capacity previously assigned to a Supplier, the Company shall reassign Underground Storage Capacity to such Supplier, and the Company and the Supplier shall address any associated increments and decrements to inventories in place pursuant to Section 13.8 of these Terms and Conditions.
- 13.6.3      If the reassignment of Peaking Capacity is required by adjustments to the MDPQ for the Supplier's Aggregation Pool, the Company shall reassign Peaking Supply to such Supplier, and the Company and the Supplier shall address any associated increments and decrements to supplies pursuant to Section 16.0 of these Terms and Conditions.



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13.7        Recall of Capacity

13.7.1        If the pro-rata shares of Capacity assignable to a Supplier declines because one or more of the Supplier's Customers has returned to Default Service, the Company shall have the right, but not the obligation, to recall from the Supplier the pro-rata shares of Capacity previously assigned to the Supplier on behalf of such Customers. The decision on whether to exercise its capacity-recall rights shall be made by the Company in its sole reasonable discretion subject to the conditions set forth in Section 13.7.2. If the Company elects to recall Capacity from a Supplier pursuant to this Section, such recall shall be made on the first Assignment Date following the effective date of the Customer's return to Default Service.

If the Company elects to recall Underground Storage Withdrawal Capacity from the Supplier pursuant to this Section, the Company shall reduce the Underground Storage Capacity associated with the affected Aggregation Pool in accordance with Section 13.8 of these Terms and Conditions. If the Company elects to reduce the MDPQ in the Supplier Service Agreement, the Company shall reduce the Peaking Supply associated with the affected Aggregation Pool in accordance with Section 16.0 of these Terms and Conditions.

13.7.2        The Company shall, in its sole reasonable discretion, determine whether to exercise its capacity-recall rights pursuant to Section 13.7.1, except in the following circumstances, where the Company shall recall capacity associated with Customers returning to Default Service at the time of the next Assignment Date in accordance with the provisions of Section 24.5 of these Terms and Conditions:

- (1)        The Supplier returning said Customers to the Company's Default Service certifies that it is ceasing all business operations in Massachusetts;
- (2)        The Supplier returning said Customers to the Company's Default Service certifies that it will no longer offer service to a particular market sector, *i.e.*, residential, small commercial and industrial ("C&I"), medium C&I, and/or large C&I Customers, and therefore, once such Customers are returned to Default Service, the Supplier is not eligible to re-enroll Customers of that type for a minimum time period of one year;
- (3)        The Supplier demonstrates that it has provided Supplier Service to the Customer for at least 12 consecutive months and that the Capacity to be recalled by the Company has been held by the Supplier, on behalf of the Customer, for a period

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equal to the sum of one or more 12-month increments. Except that, the Company will recall capacity associated with a Customer who converted from Default Service to receiving only Distribution Service during the period between November 1, 1999 and March 31, 2000, and was assigned Capacity pursuant to sections 13.3 and 13.4 as of November 1, 2000.

- (4) To the extent that the return of Customers to Default Service does not occur pursuant to the conditions set forth in Sections 13.7.2(1), (2) or (3), the Company's discretion to recall Capacity shall be exercised so as to preclude the inappropriate avoidance of Capacity-cost responsibility, while minimizing the potential for inhibiting the routine enrollment, switching and termination of Customers from Supplier Service to Default Service.

13.7.3 In the event that a Customer in a Supplier's Aggregation Pool switches to another Supplier, the Company shall recall from the former Supplier said Customer's pro-rata shares of Capacity for reassignment to the new Supplier pursuant to Section 13.4. There shall be no change in the Customer's TCQ used to determine the Customer's pro-rata shares of Capacity for reassignment to the new Supplier. The recall of such Capacity from the Customer's former Supplier and the assignment of Capacity to the new Supplier shall be made on the Assignment Date following the effective date of the Customer's switch in Suppliers.

If the Company recalls Underground Storage Withdrawal Capacity from the Customer's former Supplier, the Company shall reduce the Underground Storage Capacity associated with the affected Aggregation Pool in accordance with Section 13.8 of these Terms and Conditions. If the Company reduces the MDPQ in the Customer's former Supplier's Service Agreement, the Company shall also reduce the Peaking Supply associated with the affected Aggregation Pool in accordance with Section 16.0 of these Terms and Conditions.

13.7.4 The recall of Capacity by the Company shall entail the recall of released contracts pursuant to governing tariffs, and/or the reduction in assigned quantities set forth in the Supplier's Service Agreement. The recall of Capacity shall be executed in decrements of 200 MMBtus, commensurate with the cumulative reduction in the pro-rata shares of Capacity assignable to the Supplier that is equal to or greater than 150 MMBtus. Each decrement of Capacity assigned to the Supplier shall comprise Pipeline Capacity, Underground Storage Withdrawal Capacity and Peaking Capacity in proportion to the cumulative decrease in the pro-rata shares of Capacity recalled from the Supplier.

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- 13.7.5 In the event that a Supplier is declared ineligible to nominate Gas for thirty (30) days pursuant to Sections 11.6.6 or 12.6.3 of these Terms and Conditions, the Company shall have the right to recall any or all Capacity assigned to said Supplier. If the Supplier is reinstated at the end of such 30-day period, the Company shall reassign Capacity to the Supplier on the next Assignment Date pursuant to Section 13.4. There shall be no change in the TCQ values used to determine the Supplier's Customers' pro-rata shares of Capacity for reassignment.
- 13.7.6 In the event that a Supplier is disqualified from service for a one (1) full year pursuant to Sections 11.6.6 or 12.6.3 of these Terms and Conditions, the Company shall recall any or all Capacity assigned to said Supplier. If the Supplier is reinstated at the end of such period, the Company shall reassign Capacity to the Supplier on the next Assignment Date pursuant to Sections 13.4 and 13.5.
- 13.7.7 In the event that the Supplier fails to meet the applicable registration and certification requirements established by law or regulation, fails to satisfy the requirements and practices as set forth in Section 24.3 of these Terms and Conditions, fails to be and remain an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign capacity, fails to make timely payment under the assigned contracts, or fails to comply with or perform any of the obligations on its part established in these Terms and Conditions or in the Supplier Service Agreement, the Company shall have the right to recall permanently any or all Capacity assigned to said Supplier. This section shall also apply to a Customer acting as its own Supplier.
- 13.7.8 The Supplier shall forfeit its rights to Capacity recalled by the Company pursuant to this section. Such forfeiture shall be affected in accordance with applicable laws and regulations and the governing tariffs. In the event of capacity forfeiture pursuant to this Section, the Supplier shall be responsible to compensate the Company for any payments due under the contracts prior to forfeiture, as well as any interest due thereon. The Company will not exercise discretion in the application of the forfeiture provisions of this Section. This section shall also apply to a Customer acting as its own Supplier.
- 13.8 Underground Storage Capacity
- 13.8.1 On each Assignment Date, the Company shall release Underground Storage Capacity to a Supplier that accepts the assignment of Underground Storage Withdrawal Capacity pursuant to Section 13.4. The Company shall assign such Underground Storage Capacity consistent with the tariffs governing the release of the associated Underground Storage Withdrawal Capacity.

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- 13.8.2 If the Company assigns Underground Storage Capacity to a Supplier pursuant to Section 13.8.1 above, the Company shall transfer in-place gas inventories to the Supplier. For incremental assignments, the quantity of incremental inventories to be transferred from the Company to the Supplier shall be determined by multiplying the incremental Underground Storage Capacity assigned to the Supplier on the Assignment Date, times the applicable Storage Inventory Percentage described in Section 13.8.5. The Supplier shall be charged the Company's weighted average cost of inventories in off-system storage facilities for each Dekatherm transferred from the Company to the Supplier. The Company shall post the Company's weighted average cost of inventories, by Gas Service Area, on its Website by the 15<sup>th</sup> of the Month preceding the next Assignment Date.
- 13.8.3 In the event that the Company recalls Underground Storage Withdrawal Capacity from the Supplier pursuant to Section 13.7, the Company shall also recall Underground Storage Capacity from the Supplier. The Company shall determine the total Underground Storage Capacity to be recalled from the Supplier in accordance with the tariffs governing the Underground Storage Withdrawal Capacity returned to the Company.
- 13.8.4 If the Company recalls Underground Storage Capacity from a Supplier pursuant to Section 13.8.3, the Supplier shall transfer in-place gas inventories to the Company. The quantity of inventories to be transferred from the Supplier to the Company shall be determined by multiplying the decremental Underground Storage Capacity times the applicable Storage Inventory Percentage described in Section 13.8.5. The Supplier shall be reimbursed at the Company's weighted average cost of inventories in the off-system storage facilities serving the applicable Aggregation Pool as of the Assignment Date, for each Dekatherm transferred from the Supplier to the Company. The Company shall post the Company's weighted average cost of inventories, by Gas Service Area, on its Website by the 15<sup>th</sup> of the Month preceding the next Assignment Date.
- 13.8.5 Underground Storage Inventory Percentages shall be the ratio of the unassigned inventory levels in each storage resource that exists on the Assignment Date and the maximum Underground Storage Capacity of each storage resource less any Underground Storage Capacity previously assigned.

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13.9        Company-Managed Supplies

13.9.1        The Company shall provide access to and ascribe cost responsibility for the pro-rata shares of certain capacity contracts, including Canadian, Section 7(c) and other contracts that are not assignable to third-parties.

13.9.2        The Supplier's Service Agreement shall set forth the quantity of each Company-Managed Supply assigned to the Supplier pursuant to Sections 13.4 and 13.8.

13.9.3        The Company shall notify the Supplier of the conditions and/or restrictions on the use of Company-Managed Supplies.

13.9.4        The Company shall invoice the Supplier for its pro-rata shares of the demand charges for capacity contracts assigned to the Supplier as Company-Managed Supplies. The Company shall also flow through to the Supplier all costs incurred from the utilization of Company-Managed Supplies on behalf of the Supplier.

13.9.5        The Company shall nominate quantities to the Delivering Pipeline and/or other interstate pipelines and off-system storage operators on behalf of Suppliers to which the Company has assigned the Company-Managed Supply, provided that the requested nomination conforms to the tariffs governing the resource. The Supplier shall communicate its desired nomination quantities to the Company subject to the provisions in Sections 11.3 and 12.3 of these Terms and Conditions, unless earlier deadlines are required by the applicable contract terms.

13.10        Open-Season Capacity Assignments

A Customer that was either receiving only Distribution Service from the Company on February 1, 1999, or had a written request filed with the Company on or before February 1, 1999 to receive only Distribution Service, may elect for its Supplier to accept the assignment of its pro-rata shares of Capacity as determined by the Company in accordance with Section 13.3. The Customer must have submitted to the Company, on or before the last day of the designated Open Season, a completed application for capacity that is signed by both the Customer and Supplier. All assignments of Capacity made on behalf of such electing Customer shall be executed in accordance with Sections 13.0 and 16.0 of these Terms and Conditions.

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13.11        Capacity Mitigation Service

13.11.1       Capacity Mitigation Service is available to Suppliers that have been assigned capacity pursuant to Section 13.4 of these Terms and Conditions. Such Suppliers shall have the option to take Capacity Mitigation Service from the Company for contracts that would otherwise be released to the Supplier in accordance with Section 13.5 of these Terms and Conditions. Company-Managed Supplies and Peaking Capacity are excluded from the Capacity Mitigation Service.

13.11.2       Within five (5) Business Days prior to the Annual Reassignment Date, the Supplier must designate those contracts that would otherwise be released to the Supplier pursuant to Section 13.5, as contracts to be managed by the Company for cost mitigation in accordance with the Company's Capacity Mitigation Service. Such designation will be effective for the period November 1 through October 31. Such notice shall be communicated in accordance with the Supplier's Service Agreement.

13.11.3       The Supplier shall pay to the Company the maximum-tariff rate or lesser rate paid by the Company, including all surcharges, for the capacity contracts that are retained and managed by the Company. The Company shall bill the Supplier monthly for such charges.

13.11.4       The Company will market capacity contracts designated by Suppliers for mitigation through the Capacity Mitigation Service. The Supplier shall receive a credit on its bill for Capacity Mitigation Service equal to the pro-rata share of the proceeds earned from the marketing of such capacity contracts, less 15 percent, which will be retained by the Company in exchange for such contract management. Such credit shall be determined on a contract-specific basis at the end of each Month, and will be included in the bill sent to the Supplier in the following Month.

13.12        Capacity Exempt Customer Reliability Charge

13.12.1       The Company requires access to firm upstream pipeline, storage and peaking capacity as well as on-system peak-shaving resources to maintain the reliability of its distribution system operations. The Capacity Exempt Customer Reliability Charge (CECRC) allows the Company to recover the costs of such resources required in proportion to the level of Capacity Exempt Customer loads on its system.

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- 13.12.2 Each year, the Company shall calculate a CECRC rate per therm applicable to all Capacity Exempt Customer throughput for the annual period beginning November 1. The CECRC rate per therm and the associated derivation shall be set forth in Appendix C to these Terms and Conditions.
- 13.12.3 The CECRC rate per therm shall be calculated as follows:
- (1) Allowable CECRC costs shall equal the sum of the following;
    - (a) The product of the total Capacity Exempt Customer peak day requirements, determined prior to November 1, the system average annual unit capacity cost, and a factor of 30% (thirty percent).
    - (b) A capacity release and off-system sales revenue credit equal to the total projected annual capacity release and off-system sales margin revenues for the annual period beginning November 1 multiplied by the ratio of the total Capacity Exempt Customer peak day requirements to the total system peak day requirements.
    - (c) Any difference, positive or negative, between the costs of the CECRC as established for the previous annual period November 1 through October 31 and the actual collections from the application of the CECRC rate to Capacity Exempt Customer throughput for the corresponding period.
- 13.12.4 The total revenues recovered pursuant to the CECRC shall be credited to the Company's CGA costs in accordance with M.D.T.E. No. 36.
- 13.13 Monitoring Capacity Exempt Customer Overtakes
- 13.13.1 Overtakes associated with Capacity Exempt Customer loads threaten the reliability of Bay State's distribution system. Therefore, the Company shall monitor Supplier overtakes associated with Capacity Exempt Customer loads on Critical Days.
- 13.13.2 All Capacity Exempt Customers served by a Supplier that experiences an overtake on a Critical Day that exceeds thirty percent (30%) of the aggregate Gas Usage of Capacity Exempt Customers within its Aggregation Pool shall lose their status as exempt from the mandatory capacity assignment provisions of these Terms and Conditions. In order to determine whether a Supplier has exceeded the allowed 30% overtake for Capacity Exempt Customer loads, the Company shall perform the following calculations

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applicable to Daily-Metered and Non-Daily Metered Aggregation Pools for each day that the Company declares a Critical Day and provides notice thereof to Suppliers pursuant to Section 19.0 of these Terms and Conditions.

- (1) For Daily Metered Pools, the Company shall determine the receipts applicable to Capacity Exempt Customer loads by subtracting the total metered Gas Usage for all non-Capacity Exempt Customers in the Aggregation Pool divided by a factor of one hundred and two percent (102%) from the total deliveries for the Aggregation Pool. The total Gas Usage for all Capacity Exempt Customers in the Aggregation Pool shall be subtracted from the receipts for Capacity Exempt Customers calculated pursuant to this provision to determine the overtake applicable to Capacity Exempt Customers, if any. The percentage overtake shall be determined by dividing the Capacity Exempt Customer overtake into the total Gas Usage for all Capacity Exempt Customers in the Aggregation Pool.
- (2) For Non-Daily Metered Pools, the Company shall calculate the percentage overtake for the Aggregation Pool by subtracting the ATV from the actual receipts from the Supplier. The percentage overtake for the Aggregation Pool shall be determined by dividing the overtake for the Aggregation Pool by the ATV. The percentage overtake for Capacity Exempt Customers in the Non-Daily Metered Aggregation Pool shall equal the percentage overtake for the total Aggregation Pool.
- (3) The calculation of Capacity Exempt Customer overtakes shall not take into consideration trading of daily imbalances by Suppliers as permitted under Section 24.7.

13.13.3 All Capacity Exempt Customers of a Supplier whose overtake on a Critical Day exceeds thirty percent as calculated pursuant to Section 13.13.2 shall forego their capacity assignment exemption. Further, each Supplier serving said Capacity Exempt Customers shall be assigned capacity pursuant to these Terms and Conditions on the next allowable assignment date.



**DISTRIBUTION AND DEFAULT SERVICE  
TERMS AND CONDITIONS****APPENDIX C****Capacity Exempt Customer Reliability Charge**

<b>Row</b>	<b>Description</b>	<b>Amount</b>	<b>Calculation</b>
(1)	Capacity Exempt Customer Peak Day	XX Dth	
(2)	Average Annual Unit Capacity Cost	\$__ per Dth	
(3)	Factor	30%	
(4)	Reliability Costs		(1) x (2) x (3)
(5)	Capacity Release / OSS Margin Revenues	\$__	
(6)	Total System Design Day	XX Dth	
(7)	Capacity Release / OSS Credit		(5) x ((1)/(6))
(8)	Prior Period Under / (Over) Recovery	\$__	
(9)	Total CECRC Allowable Costs for Period	\$__	(4) + (7) + (8)
(10)	Capacity Exempt Customer Throughput	Dth	
(11)	CECRC Charge per therm	\$__	(9) / (10)

**COST OF GAS ADJUSTMENT CLAUSE****Section**

- 1.0** Purpose
- 2.0** Applicability
- 3.0** Cost of Firm Gas Allowable for Cost of Gas Adjustment Clause (CGAC)
- 4.0** Effective Date of Gas Adjustment Factor (GAF)
- 5.0** Definitions
- 6.0** Gas Adjustment Factor Formulas by High and Low Load Factor Classes
- 7.0** Interruptible Sales, Off-System Sales, and Capacity Release Revenues
- 8.0** Gas Suppliers' Refunds - Accounts 265.85 and 265.86
- 9.0** Reconciliation Adjustments – Other than Purchase Gas Working Capital
- 10.0** Reconciliation Adjustments – Purchase Gas Working Capital
- 11.0** Application of GAF to Bills
- 12.0** Information Required to be Filed with the Department
- 13.0** Other Rules
- 14.0** Customer Notification
- 15.0** Bad Debt Expense and Bad Debt Working Capital

**1.0 Purpose**

The purpose of this clause is to establish procedures that allow Bay State Gas Company ("Bay State" or the "Company"), subject to the jurisdiction of the Department of Telecommunications and Energy ("Department") to adjust, on a semiannual basis, its rates for firm gas sales service in order to recover the costs of gas supplies, along with any taxes applicable to those supplies, pipeline and storage capacity, production capacity and storage, bad debt expense associated with purchase gas costs, and the costs of purchased gas working capital, to reflect the seasonal variation in the cost of gas, and to credit all supplier refunds and the margins above the Annual Threshold associated with capacity credits from non-core sales and transportation, interruptible sales and transportation and capacity release sales, as well as revenues from the billing of the Capacity Exempt Customer Reliability Charge, to firm ratepayers.

**2.0 Applicability**

This Cost of Gas Adjustment Clause ("CGAC") shall be applicable to Bay State and all firm gas sales made by Bay State, unless otherwise designated. The application to the clause may, for good cause shown, be modified by the Department. See Section 13.0, "Other Rules."

## **COST OF GAS ADJUSTMENT CLAUSE**

### **3.0 Cost of Firm Gas Allowable for CGAC**

All costs of firm gas including, but not limited to, commodity costs, taxes on commodity, demand charges, local production and storage costs, other gas supply expense incurred to procure and transport supplies and bad debt percent (from the last general rate case) applied to allowable CGAC costs for the forecast period, transportation fees, costs associated with buyouts of existing contracts, and purchased gas working capital may be included in the CGAC. Any costs recovered through application of the CGAC shall be identified and explained fully in the semi-annual filings outlined in Section 12.0.

### **4.0 Effective Date of Gas Adjustment Factor**

The date on which the seasonal Gas Adjustment Factors ("GAF") become effective shall be the first day of the first month of each season as designated by the Company. Unless otherwise notified by the Department, the Company shall submit GAF filings as outlined in Section 12.0 of this clause at least 45 days before they are to take effect.

### **5.0 Definitions**

The following terms shall be defined in this section, unless the context requires otherwise.

- (1) **Annual Threshold** - A threshold level of margins, established annually and separately for Capacity Release, Interruptible Sales and Off-System Sales, based on the twelve months ended April 30 each year, the level above which the Company retains 25% of such margins.
- (2) **Bad Debt Expense** - is the uncollectable expense attributed to the Company's gas costs plus allowable working capital derived from the gas cost portion of bad debt.
- (3) **Base Load Requirements** - The annual quantity of gas supply needed to satisfy the lowest level of firm demand based on the average July and August loads.
- (4) **Capacity Exempt Customer Reliability Charge ("CECRC") Revenues** - The revenues from billing the CECRC to capacity exempt firm transportation customers for the cost of capacity resources needed for system reliability and based on 30% of the capacity exempt design day requirements.
- (5) **Capacity Release Revenues** - The economic benefit derived from the sale of upstream capacity.
- (6) **Carrying Charges** - Interest expense calculated on the average monthly balance using the consensus prime rate as reported in the *Wall Street Journal*.

**COST OF GAS ADJUSTMENT CLAUSE**

- (7) **Economic Benefit** - The difference between the revenues received and the marginal cost determined to serve non-core customers.
- (8) **Interruptible Sales Margins** - The economic benefit derived from the interruptible sale of gas downstream of the Company's distribution system.
- (9) **Inventory Finance Charges** - As incurred or billed each month for the carrying costs on the value of the balance of inventory gas for the respective month. The total charges shall represent an accumulation of the projected monthly charges as calculated using the monthly average of financed inventory at the existing (or anticipated) financing rate of the Company or through a trust or other financing vehicle.
- (10) **Local Production Capacity and Storage Costs** - Include the ancillary supply costs of providing local manufactured gas, gas dispatching, gas acquisition, and miscellaneous A&G costs as determined in the Company's most recent rate proceeding.
- (11) **SMBA** – Simplified Market Based Allocation Method - Used in determining the allocation of gas costs among High and Low Load Factor classes.
- (12) **Non-Core Commodity Costs** - The commodity cost of gas assigned to non-core sales to which the GAF is not applied. Non-core sales include sales made under interruptible contracts, non-core contracts and off-system sales.
- (13) **Non-Core Sales Margins** – The economic benefit derived from non-core transactions to which the GAF is not applied, including interruptible sales and other non-core sales generated from the use of the Company's Gas Supply resource portfolio.
- (14) **Off-System Sales Margin** - The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.
- (15) **Number of Days Lag** - The number of days lag to calculate the purchased gas working capital requirement as approved by the Department.
- (16) **Off-Peak Commodity** – Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the off-peak season.
- (17) **Off-Peak Demand** - Unless otherwise approved by the Department, the gas supply demand and transmission capacity assigned by the Company to serve firm load in the off-peak season.
- (18) **Off-Peak Period** - May through October.
- (19) **Peak Commodity** - Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the peak season.
- (20) **Peak Demand** - Unless otherwise approved by the Department, gas supply demand, peaking demands, storage and transmission capacity assigned by the Company to service firm load in the peak season.
- (21) **Peak Period** - November through April.
- (22) **PR Allocator** - The percentage allocated for the portion of annual capacity charges assigned to the seasons calculated in each CGA filing.

**COST OF GAS ADJUSTMENT CLAUSE**

- (23) **Pretax Weighted Cost of Capital** - The result of the calculation of the weighted cost of capital minus the weighted cost of debt, divided by one, minus the currently effective combined tax rate, plus the weighted cost of debt.
- (24) **Purchased Gas Working Capital** - The allowable working capital derived from peak and off-peak, demand and commodity related costs.
- (25) **Tax Rate** is the combined State and Federal income tax rate.
- (26) **Weighted Cost of Capital** is the weighted cost of capital as set in the Company's most recent base rate case.
- (27) **Weighted Cost of Debt** is the weighted cost of debt as set in the Company's most recent base rate case.

**6.0 Gas Adjustment Factor (GAF) Formula**

The Gas Adjustment Factor ("GAF") Formula shall be computed on a semiannual basis using forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

A separate seasonal GAF will be computed for the combined Low Load Factor classes namely Rates R-3, R-4, G-40, G-41, G-42 and G-43; and for the combined High Load Factor classes namely Rates R-1, R-2, OL, G-50, G-51, G-52 and G-53. The calculation of each seasonal GAF utilizes information periodically established by the DTE. The table below lists the following approved cost factors as approved in D.T.E. 05-27:

Local Production & Storage Cost	\$7,430,587
LNG/LPG Production Cost included above	\$5,045,484
Bad Debt Expense Percentage	2.15%

**Peak GAF Formula**

The Peak GAF shall be comprised of a peak demand factor (DFp), a peak commodity factor (CFp), a peak production and storage demand factor (PSp), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF) defined in Section 15.00, for the Company's High and Low Load Factor classes and calculated at the beginning of the peak season according to the following formula:

$$\text{GAF}^x = \text{DFp}^x + \text{PSp}^x + \text{CFp}^x + \text{BDF} - \text{R1} - \text{R2}$$

**COST OF GAS ADJUSTMENT CLAUSE****Peak Demand Factor (DFp) Formula**

$$DFp^x = \frac{Dp^x - NCSMp^x - CECRCR}{P : Sales^x} + RFpd + WCFpd$$

**and:**

$$Dp^x = BASEDp^x + REMAINDp^x + PSp^x$$

**and:**

$$NCSMp^x = CRR^x + ISM^x + NTSM^x$$

**and:**

$$RFpd = Rpd/P:Sales$$

**and:**

$$WCFpd = \frac{[(WCApd \times CC) - (WCApd \times CD)] + (WCApd \times CD) + WCRpd}{(1 - TR)} \times P : Sales$$

**and:**

$$WCApd = Dp \times (DL/365)$$

**Where:**

BASEDp	Peak period base use demand charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August's daily loads.
CC	Weighted cost of capital as defined in Section 500.
CD	Weighted cost of debt as defined in Section 5.00.
CECRCR	Revenues from billing the Capacity Exempt Customer Reliability Charge.
CRR	The returnable Capacity Release Revenues allocated to the peak period. See Section 7.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dp	Demand Charges allocated to the peak period as defined in Section 5.00.

**COST OF GAS ADJUSTMENT CLAUSE**

NCSMp <sup>x</sup>	The sum of the returnable Interruptible Non-Core Sales Margins, the returnable Capacity Release Revenues and the Off-System margins.
ISM	The returnable Interruptible Sales Margins allocated to the peak period. See Section 7.00.
NTSM	The returnable Off-System Sales Margins allocated to the peak period. See Section 7.00.
P:Sales	Forecasted sales volumes associated with the peak period.
REMAINDp	Peak period remaining use demand charges assigned to classes on the basis of their load's contribution to the design day load less their base use entitlements to pipeline supplies. This remaining capacity cost is allocated to seasons using the Proportional Responsibility (PR) allocator.
RFpd	Peak demand charge reconciliation adjustment factor per billed peak sales volume associated with demand charges related to the peak period.
Rpd	Reconciliation Costs - Peak demand deferred gas costs, Account 175.21 balance, inclusive of the associated Account 175.21 interest, as outlined in Section 9.00.
TR	Combined Tax Rate as defined in Section 5.00
WCApd	Demand charges allowable for working capital application as defined in Section 10.00.
WCFpd	Working Capital allowable factor per billed peak sales volume associated with demand charges allocated to the peak period as defined in Section 10.00.
WCRpd	Working Capital reconciliation adjustment associated with peak demand charges - Account 176.24 balance as outlined in Section 10.00.
x	Designates Load Factor Specific allocation of costs, based on Simplified Market Based Allocation factors as determined in the Company's most recent rate proceeding.
PSpx	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

**Peak Commodity Factor (CFp) Formula**

$$CFp^x = \left[ \frac{Cp^x - NCCCp^x + FC^x}{P : Sales^x} \right] + RFpc + WCFpc$$

**and:**

$$Cp^x = BASECp^x + REMAINCpx$$

**and:**

$$RFpc = Rpc / P:Sales$$

**and:**

**COST OF GAS ADJUSTMENT CLAUSE**

$$\text{WCFpc} = \frac{[(\text{WCApc} \times \text{CC}) - (\text{WCApc} \times \text{CD})] + (\text{WCApc} \times \text{CD}) + \text{WCRpc}}{(1 - \text{TR})}$$

P: Sales

**and:**

$$\text{WCApc} = \text{Cp} \times (\text{DL}/365)$$

**Where:**

BASECp	Peak period base use commodity charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August daily loads.
CC	Weighted costs of capital as defined in Section 5.00
CD	Weighted costs of debt as defined in Section 5.00.
Cp	Commodity Charges allocated to the peak period as defined in Section 5.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
FC	Inventory finance charges as defined in Section 5.00.
NCCCp	Non-Core Commodity Costs allocated to the peak period as defined in Section 5.00.
P:Sales	Forecasted sales volumes associated with the peak period.
REMAINCP	Peak period remaining use commodity charges computed as dispatched commodity costs less base use commodity costs.
RFpc	Peak commodity charge reconciliation adjustment factor per billed peak sales volume associated with commodity charges related to the peak period.
Rpc	Reconciliation Adjustment Costs - Account 175.23 balance, inclusive of the associated Account 175.23 interest, as outlined in Section 9.00.
R	Combined Tax rate as defined in Section 5.00.
WCApc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFpc	Working Capital allowable factor per peak sales volume associated with commodity charges allocated to the peak period as defined in Section 10.00.
WCRpc	Working Capital reconciliation adjustment associated with peak commodity charges Account 175.24 balance as outlined in Section 10.00.
x	Designates Load Factor class specific allocation of costs, based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.

**Off-Peak GAF Formula**

The Off-Peak GAF shall be comprised of an off-peak demand factor (Dfop) an off-peak



**COST OF GAS ADJUSTMENT CLAUSE**

production and storage demand factor (PSop), an off-peak commodity factor (Cfop), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF), defined in Section 15.00 for the Company's High and Low Load Factor classes, and calculated at the beginning of the off-peak season according to the following formula.

$$\text{GAFop}^X = \text{DFop}^X + \text{CFop}^X + \text{PSop}^X + \text{BDF} - \text{R1} - \text{R2}$$

**Off-Peak Demand Factor (DFop) Formula**

$$\text{DFop}^X = \frac{\text{Dop}^X}{\text{OP:Sales}^X} + \text{RFopd} + \text{WCFopd}$$

**and:**

$$\text{Dop}^X = \text{Sum:BLDop}^X + (\text{Sum:BLDXop}^X \times (1 - \text{PR}))$$

**and:**

$$\text{RFopd} = \text{Ropd} / \text{OP:Sales}$$

**and:**

$$\text{WCFopd} = \frac{\frac{[(\text{WCAopd} \times \text{CC}) - (\text{WCAopd} \times \text{CD})]}{(1 - \text{TR})} + (\text{WCAopd} \times \text{CD}) + \text{WCRopd}}{(\text{OP:Sales})}$$

**and:**

$$\text{WCAopd} = \text{Dop} (\text{DL}/365)$$

**Where:**

BLDop	Demand charges billed to the Company during the off peak period for the portion of base demand associated with serving base load requirements as defined in Section 5.00.
BLDXop	Base demand costs in excess of demand costs associated with base load level billed to the Company during the off-peak period.

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CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dop	Demand charges allocated to the off-peak period as defined in Section 5.00.
OP:Sales	Forecasted sales volumes associated with the off-peak period.
PR	Proportional Responsibility Allocator - A percentage representing a portion of capacity/product charges incurred in the off-peak season and assigned to the peak period calculated in each CGA filing as defined in Section 5.0.
RFopd	Off-peak demand charge reconciliation adjustment factor per billed off peak throughput volume associated with demand charges related to the off peak period.
Ropd	Reconciliation Costs - Account 175.11 balance, inclusive of the associated Account 175.11 interest, as outlined in Section 9.00.
SMBA	Simplified Market Based Allocator – Load Factor specific allocator as defined in Section 5.00
TR	Combined Tax rate as defined in Section 5.0
WCAopd	Demand charges allowable for working capital application as defined in Section 6.1.
WCFopd	Working Capital factor allowable per billed off-peak sales associated with demand charges allocated to the off-peak period as defined in Section 10.0
WCRopd	Working Capital reconciliation adjustment associated with off-peak demand charges balance account 175.14 balance as outlined in Section 10.0.
x	Designates Load Factor specific allocation of costs based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.
PS <sub>op</sub> <sup>x</sup>	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to off-peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

**Off-Peak Commodity Factor (CFop) Formula**

$$CFop^x = \frac{Cop^x - NCCCop^x}{OP : Sales^x} + RFopc + WCFopc$$

**and:**

$$Cop^x = Sum:OPC^x - BOao^x - INJop^x - LIQop^x$$

**and:**

$$BOao^x = [(BOop - (BOvolop \times (TPop/TPvolop))) SMBA^x]$$

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$$RFopc = Ropc/OP:Sales$$

**and:**

$$WCFopc = \frac{[(WCAopc \times CC) - (WCAopc \times CD)]}{(1 - TR)} + \frac{(WCAopc \times CD) + WCRopc}{OP : Sales}$$

**and:**

$$WCAopc = Cop \quad (DL/365)$$

**Where:**

BOao	LNG Boil-off allocation as defined in Section 9.00.
BOop	Cost of LNG Boil-off during the off-peak period.
BOvolop	LNG Boil-off volumes purchased in the off-peak period.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00.
Cop	Commodity Charges billed to the off-peak period as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers. See Section 10.00.
INJop	Injections into underground storage during the off-peak period.
LIQop	Liquefactions into storage during the off-peak period.
NCCCop	Non-core commodity costs allocated to the off-peak period as defined in Section 6.05.
OP:Sales	Forecasted sales volumes associated with the off-peak period.
OPC	Commodity charges associated with gas supply sent out in the off-peak season as defined in Section 5.00.
RFopc	Off peak commodity charge reconciliation adjustment factor per billed off peak sales volume associated with commodity charges related to the off-peak period.
Ropc	Reconciliation Adjustment Cost - Account 175.13 balance, inclusive of the associated Account 175.13 interest, as outlined in Section 9.00.
TPop	Total pipeline commodity purchase charges for the off-peak period.
TPvolop	Total pipeline purchase volumes for the off-peak period.
TR	Combined Tax rate as defined in Section 5.00.
WCAopc	Commodity charges allowable for working capital application as defined in Section 10.00.

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WCFopc	Working Capital allowable per off-peak sales volume associated with commodity charges allocated to the off-peak period as defined in Section 10.00.
WCRopc	Working Capital reconciliation adjustment associated with off-peak commodity charges - Account 176.14 balance, as outlined in Section 10.00.
x	Designates Load Factor specific allocation of costs, based on Simplified Market Based Allocation factors.

**7.0 Interruptible Sales, Off-System Sales and Capacity Release Revenues**

A threshold level of margins will be established annually and separately for Interruptible Sales, Off-System Sales and Capacity Release Revenues. Any margins earned in excess of the predetermined level shall be divided between the Company and its firm sales customers under a 25/75 sharing arrangement. The threshold level of margins shall be adjusted to reflect additions or losses from Customers who switch from FT, FS or Interruptible Transportation ("IT") to IS and conversely, from IS to FT, FS or IT. The Company shall adjust the threshold level annually to reflect Interruptible Sales, Off-System sales, and capacity release revenues for the twelve-month period ending April 30 of each year.

Margins from Interruptible Sales, Off-System Sales and Capacity Release will be reflected as separate credits in the peak season GAF and shall be calculated as the sum of the following:

- (1) 100% of the margins earned up to the predetermined threshold level.
- (2) 75% of the margins earned in excess of the predetermined threshold level.

**8.0 Gas Suppliers' Refunds - Accounts 265.85 and 265.86**

Refunds from upstream capacity suppliers and suppliers of gas are credited to Account 265.85, "Refund-November" if received during the months of March through August, and to Account 265.86 "Refund-May", if received during the months of September through February.

A refund program shall be initiated with each semiannual GAF filing and shall remain in effect for a period of one year. The balance in Account 265.85 shall be placed into a refund program with each November filing. The balance in Account 265.86 shall be placed into a refund program with each May filing. The total dollars to be placed into a given refund program shall be net of

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over/under-returns from expired programs plus refunds received from suppliers since the previous program was initiated. The Company shall track and report on all Account 265.85 and Account 265.86 activities. If during any twelve-month period commencing with the billing month of November for Account 265.85 and May for Account 265.86, the projected supplier refund factor is less than one-hundredth of a cent per therm (\$0.0001), the respective supplier refund account balance shall be transferred into Account 175.26 or Account 175.16 for the November and May filings respectively.

**Gas Supplier's Refund Factors**

**R1** The per unit supplier refund associated with the Refund – May program. The following formula shall be used to calculate the R1 factor.

$$R1 = \frac{R1\$ + I}{A:Sales}$$

**Where:**

R1\$ Ending balance in Account 265.86 “Refund – May”  
I Total forecasted interest calculated on the R1\$ balance computed at the consensus prime rate as reported in the *Wall Street Journal* based on a 365 day year.  
A:Sales Forecasted annual firm sales volumes.

**R2** The per unit supplier refund associated with the Refund – November program. The following formula shall be used to calculate the R2 factor.

$$R2 = \frac{R2\$ + I}{A:Sales}$$

**Where:**

R2\$ Ending balance in Account 265.85 “Refund – November”  
I Total forecasted interest calculated on the R2\$ balance computed at the Federal Reserve Prime Rate based on a 365 day year.  
A:Sales Forecasted annual firm sales volumes.

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**9.0     Reconciliation Adjustments – Other than Working Capital**

- (1)     The following definitions pertain to reconciliation adjustment calculations:
- (a) Capacity Costs Allowable per Peak Demand Formula shall be:
    - i.     Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in the peak season.
    - ii.    Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.
    - iii.   Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.
    - iv.    Charges associated with peaking, production and storage capacity to serve firm load in the peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service.
    - v.     Credits associated with Non-Core Sales Margins or economic benefits from capacity release, off-system sales for resale and interruptible sales margins allocated to the firm sales service.
    - vi.    Credits associated with daily imbalance charges billed transportation customers in the peak period.
    - vii.   Credits associated with Capacity Exempt Customer Reliability Charges billed to Capacity Exempt Customers in the peak period in accordance with M.D.T.E. No. 35, Section 13.12.
    - viii. Peak demand Carrying Charges as defined in Section 5.00.
  - (b) Gas Costs Allowable Per Peak Commodity Formula shall be:
    - i.     Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the peak season, plus a reallocation of LNG boiloff costs from the off-peak season, determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchased in the off-peak period, less the cost of injections and liquefaction into storage.
    - ii.    Credit non-core commodity costs assigned to non-core customers to which the CGAC does not apply, as defined in Section 6.06 (NCCCP).
    - iii.   Inventory finance charges (FC).
    - iv.    Peak commodity Carrying Charges as defined in Section 5.00.

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(c) Capacity Costs Allowable Per Off-Peak Demand Formula shall be:

- i. Charges associated with transmission capacity and product demand procured by the Company to serve base load requirements in the off peak season.
- ii. Charges associated with transmission capacity and product demand procured by the Company to serve firm load in excess of base load requirements in the off-peak period
- iii. Credits associated with daily imbalance charges billed transportation customers in the off peak period.
- iv. Off-peak demand Carrying Charges as defined in Section 5.00.
- v. Other A & G and Acct. 851 charges associated with peaking production and storage capacity to serve firm load in the off-peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service

(d) Gas Costs Allowable Per Off-Peak Commodity Formula shall be:

- i. Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the off-peak season, less the reallocation of LNG boiloff costs determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchases in the off-peak period, less the cost of injections and liquefactions into storage.
- ii. Credits associated with Non-core commodity costs from non-core sales to which the GAF is not applied, as defined in Section 5.00.
- iii. Off-peak commodity Carrying Charges as defined in Section 5.00.

(2) **Calculation of the Reconciliation Adjustments**

Account 175 contains the accumulated difference between gas cost revenues and the actual monthly gas costs incurred by the Company. The Company shall separate Account 175 into Peak Demand (Account 175.21), Peak Production and Storage Demand (175.22), Peak Commodity (Account 175.23), Off-Peak Demand (Account 175.11), Off-Peak Production and Storage Demand (175.12) and Off-Peak Commodity (Account 175.13). Account 175.21 shall contain the accumulated difference between revenues toward capacity costs calculated by multiplying the Peak Demand Factor for the High and Low Load Factor classes, (DFp<sup>x</sup>) times monthly firm sales volumes for High and Low Load Factor classes, and the total capacity costs allowable per the peak demand formula. Account 175.22 shall contain the accumulated difference between revenues

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toward gas costs as calculated by multiplying the Peak Commodity Factor for the High and Low Load Factor classes,  $(CF_p^x)$  times monthly firm sales volumes for High and Low Load Factor classes, and the total commodity costs allowable per the peak commodity formula. Account 175.22 shall contain the accumulated difference between revenues as calculated by multiplying the Peak Production and Storage Demand Factor for the High and Low Load Factor class,  $(PS_p^x)$  times monthly firm sales volumes for the High and Low Load Factor classes, and the total production and storage costs allowable per the peak production and storage demand formula. Account 175.11 shall contain the accumulated difference between revenues toward capacity costs calculated by multiplying the Off-Peak Demand Factor for the High and Low Load Factor classes,  $(DFop^x)$  times monthly firm sales volumes for the High and Low Load Factor classes, and the total capacity costs allowable per the off-peak demand formula. Account 175.13 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Off-Peak Commodity Factor for the High and Low Load Factor classes,  $(CFop^x)$  times monthly firm sales volumes for the High and Low Load Factor classes, and the total commodity costs allowable per the off-peak commodity formula. Account 175.12 shall contain the accumulated difference between revenues as calculated by multiplying the Off-Peak Production and Storage Demand Factor for the High and Low Load Factor classes,  $(PS_{op}^x)$  times monthly firm sales volumes for the High and Low Load Factor classes, and the total production and storage costs allowable per the off-peak production and storage demand formula.

Carrying Charges as defined in Section 5.00 shall be added to each end-of-the-month balance. The peak demand reconciliation adjustment factor (RFpd) shall be determined for use in the peak GAF calculation by dividing the peak demand account (175.21) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak production & storage demand reconciliation adjustment factor (RFppsd) shall be determined for use in the peak GAF calculation by dividing the peak production and storage demand account (175.22) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak commodity reconciliation adjustment factor (RFpc) shall be determined for use in the peak GAF calculation by dividing the peak commodity account (175.23) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The off-peak demand reconciliation adjustment factor (RFopd) shall be determined for use in the off peak GAF calculation by dividing the off-peak demand account (175.11) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak production and storage demand reconciliation adjustment factor (RFoppsd) shall be determined for use in the off-peak GAF calculation by dividing the off-peak production and storage demand account (175.12) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-



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peak period. The off-peak commodity reconciliation adjustment factor (RFopc) shall be determined for use in the off-peak GAF calculation by dividing the off-peak commodity account (175.13) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period.

The peak period reconciliation will be filed thirty (30) days prior to the peak period GAF filing, which is seventy-five (75) days prior to the effective date.

The off-peak period reconciliation shall be filed thirty (30) days prior to the off-peak period GAF filing, which is seventy-five (75) days prior to the effective date.

#### **10.0 Working Capital Reconciliation Adjustments**

- (1) The following definitions pertain to reconciliation adjustment calculations:
  - (a) Working Capital Gas Costs Allowable Per Peak Demand Formula shall be:
    - i. Charges associated with upstream storage, transmission capacity, and product demand procured by the Company to serve firm load in the peak season.
    - ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.
    - iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.
    - iv. Carrying Charges
  - (b) Working Capital Gas Costs Allowable Per Peak Commodity Formula shall be:
    - i. Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the peak season, plus a reallocation of LNG boiloff costs from the off-peak season, determined by the product of the difference in the average costs of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchased in the off-peak period, less the cost of injections and liquefactions into storage.
    - ii. Non-Core Commodity Costs associated with non-core sales to which the GAF is not applied.

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- iii. Carrying charges.
- (c) Working Capital Gas Costs Allowable Per Off-Peak Demand Formula shall be:
- i. Charges associated with transmission capacity procured by the Company to serve base load requirements in the off peak season.
  - ii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the off-peak period.
  - iii. Carrying charges.
- (d) Working Capital Gas Costs Allowable Per Off-Peak Commodity Formula shall be:
- i. Charges associated with gas supplies, including any applicable taxes, procured by the company to serve firm load in the off-peak season, less the reallocation of LNG boiloff costs determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchases in the off-peak period, less the cost of injections and liquefactions into storage.
  - ii. Non-core commodity costs associated with non-core sales to which the GAF is not applied, as defined in section 6.05.
  - iii. Carrying charges.
- (2) The peak and off-peak, demand, and commodity working capital requirements shall be calculated by applying the Company's days lag divided by 365 days to the working capital costs allowable per each formula.
- (3) The peak and off-peak, demand, and commodity working capital allowances shall each be calculated by applying the Company's weighted cost of capital to each working capital requirement to calculate the respective returns on working capital. The interest portion of each working capital allowance is calculated by multiplying each working capital requirement by the weighted cost of debt. This portion is tax deductible. The return on each working capital less the interest portion of each working capital is then divided by one minus the tax rate. This figure plus the interest calculated above equals the working capital allowance for each.
- (4) Calculation of the Reconciliation Adjustments
- Accounts 175.14, 175.13, 175.24, and 175.23 contain the accumulated difference between working capital allowance revenues and the actual monthly working capital allowance costs as calculated from actual monthly costs for the Company plus Carrying

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Charges as defined in Section 5.00.

The components of the Company's purchased gas days lag shall be recalculated each season based upon actual CGAC seasonal data. This recalculated days lag will be used in the calculation of the working capital allowance revenues. Each Account 175 shall contain the accumulated difference between revenues toward the working capital allowance and the working capital allowance.

The peak demand working capital reconciliation adjustment shall be determined for use in the peak demand factor calculations incorporating the peak demand working capital account 175.14 balance as of the peak reconciliation date designated by the Company. A peak commodity working capital reconciliation adjustment shall be determined for use in the peak commodity factor calculations incorporating the peak commodity working capital account 175.13 balance as of the peak reconciliation date designated by the Company. An off-peak working capital reconciliation adjustment (WCRopd) shall be determined for use in the off -peak demand factor calculations incorporating the off-peak demand working capital account (175.24) balance as of the off-peak reconciliation date designated by the Company. An off-peak commodity working capital reconciliation adjustment (WCRopc) shall be determined for use in the off-peak commodity working capital account (175.23) balance as of the off-peak reconciliation date designated by the Company.

### **11.0 Application of GAF to Bills**

The Company will employ the GAFs as follows: The peak season rates to each Load Factor class shall be calculated by adding the respective peak demand factor and the peak commodity factor. The off-peak season rates to each Load Factor class shall be calculated by adding the respective off-peak demand factor and the off-peak commodity factor. The GAFs (\$/therm) for each Load Factor class for each season shall be calculated to the nearest one-hundredth of a cent per therm (\$0.0001) and will be applied to each customer's monthly sales volume within the corresponding Load Factor class.

### **12.0 Information Required to be Filed with the Department**

Information pertaining to the cost of gas adjustment shall be filed with the Department in accordance with the Company's standardized forms approved by the Department. Required filings include a semiannual GAF filing, which shall be submitted to the Department at least 45 days before the date on which a new GAF is to be effective.

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Additionally the Company shall file with the Department a complete list of all gas costs claimed as recoverable through the CGAC over the previous season, as included in the seasonal reconciliation. This information shall be submitted with each seasonal GAF filing, along with complete documentation of the reconciliation adjustment calculations.

### **13.0 Other Rules**

- (1) The Department may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.
- (2) The Company may, at any time, file with the Department an amended GAF. An amended GAF filing must be submitted 10 days before the first billing cycle of the month in which it is proposed to take effect.
- (3) The Department may, at any time, require the Company to file an amended GAF.
- (4) The operation of the cost of gas adjustment clause is subject to all powers of suspension and investigation vested in the Department by G.L. c.164.

### **14.0 Customer Notification**

The Company will design a notice, which explains in simple terms to customers the GAF, the nature of any change in the GAF and the manner in which the GAF is applied to the bill. The Company will submit this notice for approval at the time of each GAF filing.

Upon approval by the Department, the Company must immediately distribute these notices to all of its customers either through direct mail or with its bills.

### **15.0 Bad Debt Allowance**

#### **15.01 Purpose**

The purpose of this provision is to establish a procedure that, subject to the jurisdiction of the Department, allows Bay State to adjust, on a semi-annual basis, its rates for the recovery of Bad Debt Expense

#### **15.02 Bad Debt (BDF) Formula**

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The Bad Debt (BDF) Formula shall be computed on an annual basis using forecasts of bad debt expense associated with gas costs, gas costs, carrying charges, sales volumes, and a working capital allowance. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing. The forecast of bad debt expense associated with gas costs shall be based on the Company's projected gas costs in the respective seasonal GAF filings and the percent of net write-offs to total firm revenues as determined in the Company's last rate proceeding.

The calculation at the beginning of the off-peak season shall be on a projected annual basis. The calculation at the beginning of the peak season will update the remaining months of the projected annual period with actual bad debt expenses and collections for the available months and projections for the remaining months of the annual period. The following formula shall be used to calculate the Bad Debt factor.

$$\text{BDF} = \frac{\text{BD} + \text{RAbd} + \text{WCbd}}{\text{A:Sales}}$$

**and:**

$$\text{WCbd} = \frac{(\text{WCAbd} * \text{CC}) - (\text{WCAbd} * \text{CD})}{(1 - \text{TR})} + (\text{WCAbd} * \text{CD})$$

**and:**

$$\text{WCAbd} = \text{BD} * (\text{DL}/365)$$

**Where:**

**A:Sales** Forecast annual sales volumes.

**BD** Forecast Bad Debt Expense as defined in Section 5.00; derived by multiplying the forecast annual gas costs by the percent of annual net write-offs to annual firm revenues as determined in D.T.E. 05-27.

**CC** Weighted cost of capital as defined in Section 5.00.

**CD** Weighted cost of debt as defined in Section 5.00.

**DL** Number of days lag from the purchase of gas from suppliers to the payment by customers.

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RAbd	Bad Debt Expense reconciliation adjustment - Account 175.31 balance.
TR	Combined Tax rate as defined in Section 5.00.
WCAbd	Bad Debt allowable for working capital application defined as the costs associated with the gas cost portion of bad debt incurred by the Company to serve firm load.
WCbd	Working Capital Allowance associated with the gas portion of bad debt for the period including the Pretax Weighted Cost of Capital as defined in Section 5.00.

**15.03 Bad Debt Reconciliation Adjustment**

Account 175.31 shall contain the accumulated difference between the annual revenues toward bad debt, as calculated by multiplying the bad debt factors (BDF) times monthly firm sales volumes, and the annual allowed Bad Debt expenses, allowed working capital on Bad Debt and Carrying Charges as defined in Section 5.00.

An annual bad debt reconciliation adjustment (RAbd - as defined in Section 15.02) shall be determined for use in the bad debt factor calculations incorporating the bad debt working capital account (175.32) balance as of the reconciliation date designated by the Company.

- (a) Costs Allowable per Bad Debt Formula shall be:
- i. Un-collectable gas costs incurred by the Company to serve firm sales load, as determined by deriving the portion of actual net write-offs associated with gas cost collections.
  - ii. Account 175.32 – Bad Debt, Carrying Charges.
  - iii. Working Capital Gas Costs Allowable per Bad Debt Formula, which shall be charges associated with bad debt incurred by the Company to serve firm sales load and applied to the working capital formula.